Modeling CO_2 storage Using Coupled Reservoir-Geomechanical Analysis

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Abstract: At In Salah, Algeria, excess CO_2 from the produced oil and gas is re-injected into the ground as part of a CO_2 storage demonstration project where one of the main goals is to verify long-term storage capacity from short-term monitoring. In this context, a significant heave at the injection sites is observed and a 3D FEM model is defined to verify it. Some additional features are introduced to investigate the impact of certain model parameters; (1) introduction of a high-permeable lower-caprock to investigate the effect on the heave from highly fractured media above the reservoir and (2) the effect of a vertical fault plane in the model to investigate the heave-signature on the surface when a fault intersects the caprock.

The high observed uplift of the surface above the injection site is supported by simulations. Most of the observed uplift can be explained by the poro-elastic expansion of the injection zone. It is also shown that by looking at time evolution curves of surface heave and heave footprint at the surface above an injection site it is possible to say something about the geology, like high-permeable fracture zones and fault planes.

Keywords: Two phase flow modeling, geomechanics, CO2 storage

1. Introduction

Natural gas from In Salah, Algeria, contains up to 10% CO_2 that needs to be reduced to 0.3%, resulting in app. 1 $MtCO_2$/year to be re-injected into the water leg of the Krechba Carboniferous Sandstone reservoir (20 m thick) producing gas through three wells. The sandstone reservoir where the CO_2 is injected is located at 1800-1900 m depth (porosity app. 11-20% and permeability of 10mD) and is capped with low-permeable mud- and sandstone (porosity of app. 17% and permeability of 10^{-19}-10^{-21} m^2). Due to the relatively low permeability of the reservoir the CO_2 is injected through a 1-1.5 km line at a rate of app. 1 $MtCO_2$/year creating an injection over-pressure of app. 10 bar. This has in a short time resulted in a significant heave of up to 5-8 mm/year at the injection wells extending several kilometers and subsidence of up to 2-3 mm/year at the production wells. This is verified by satellite airborne radar interferometry (InSAR) that can detect subtle ground deformation on a millimeter-scale. Here, a constant injection rate of 30 kg/s is applied (app. 0.95 $MtCO_2$/year), resulting in a maximum over-pressure of 14 bars after 3-4 years.

2. Physics

A 3D FEM model describing two-phase flow and poroelasticity is implemented in COMSOL Multiphysics. The two-phase flow equations are the general mass balance equations, defined using general form application modes. In a fractional flow formulism the two-phases are treated as a total fluid flow of a single mixed fluid, and the individual phases as fractions of the total flow. The coupling to poroelasticity equation is through the additional source term Q_s in the mass balances as:

$$Q_s=-\alpha\,\partial\varepsilon_v/\partial t \qquad (1)$$

where α is the Biot constant and ε_v is the volumetric strain from the poroelasticity equation. The permeability also changes due to deformation, but here it is defined as constant. Effective porosity can be described by the volumetric strain:

$$\phi=(1-\varepsilon_v)\phi_0$$

where ϕ and ϕ_0 is the effective and initial porosity, respectively. Effective porosity and the additional source terms represent a direct coupling between fluid flow and poroelasticity. The Capillary pressure function and relative permeability are expressed by Brooks-Corey relations.

Linear Biot poroelasticity theory is implemented to account for elastic response to fluid flow through a saturated porous solid where an increase in fluid pressure will cause the solid to swell. The formulation is restricted to linear elastic solids undergoing quasistatic small deformations and is here based on Naviers equation for the study of displacements, stresses, and strains.

3. Model, results and discussion

The model, inspired by Rutquist et. al. 2009, of the injection well called KB501, is 20x20x4 km (chosen to give an injection over-pressure of 10-15 Bar), a cross section of the model is shown in figure 1. The injection well is located 1810 m below surface within a 20 m thick reservoir layer. The reservoir is considered highly fractured and as such has a high effective permeability K_{eff} = 200 mD, compared to intrinsic permeability of 10 mD. Two simplifications are done in the model; dissolution of CO_2 in water is ignored and residual saturation is zero for both phases. The lateral boundaries have constant fluid pressure and no horizontal displacement, the bottom boundary is fixed and has a no-flow condition and the top boundary has a constant fluid pressure and is free to move.

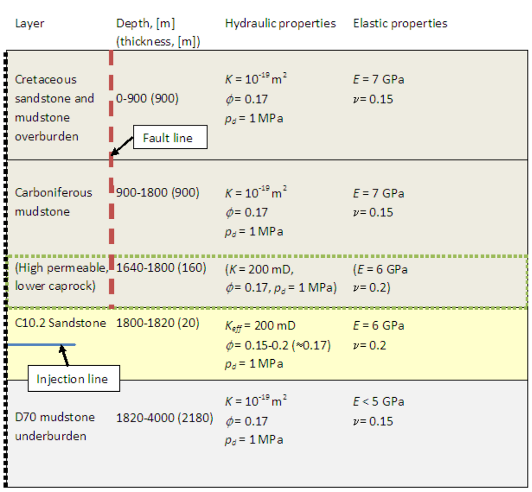

Figure 1. Schematic representation of the Base case model; geometry and model parameters. K is permeability, ϕ is porosity, p_d is entry pressure, E is Young's modulus and ν is Poisson ratio. Black dashed line corresponds to a symmetry plane in 3D. The red dashed line illustrates the fault line through the caprock, in 3D it represents a fault plane that is located 250m away from the end of the injection line.

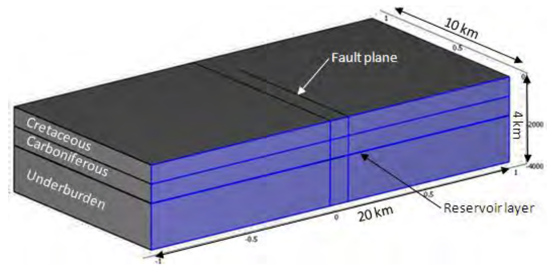

Figure 2. 3D model illustrated with a symmetry plane (blue faces). In addition, the high-permeable lower caprock layer (not illustrated) is located between the sandstone reservoir and the caprock.

The best-guess estimate of the available parameters, in figure 1, are modelled and referred to as Base case, in addition two more cases are examined, a summary of the models is given in table 1.

Table 1. Summary of model cases.

Model	Description
Base	Model defined as in figure 1, except the high-permeable lower caprock layer
Fracture	Simulating a fractured layer by inserting a high permeable lower caprock layer; permeability: 200 mD (in effect increasing the thickness of the reservoir)
Fault	Add a fracture/fault plane through the caprock perpendicular to injection line and 250 m to the side of the end of the injection line. Aperture: 2 cm, permeability: 1 D (Iding et. al. 2009)

The heave at the various injection wells at In Salah from two different references is shown in figure 3. The modeled heave for Base case model and Fracture case model is given in figure 4, left and right, respectively. From left figure 4 one can see that the magnitude of the heave is comparable between the measured and modeled data (Base case).

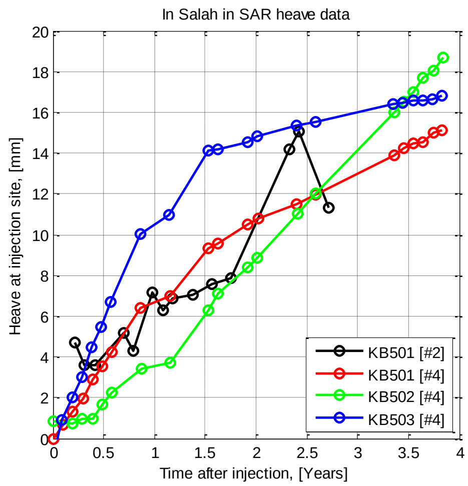

Figure 3. Measured heave data at the injection wells from two different references: #2, Rutquist et. al. 2009 and #4, Onuma et. al. 2009.

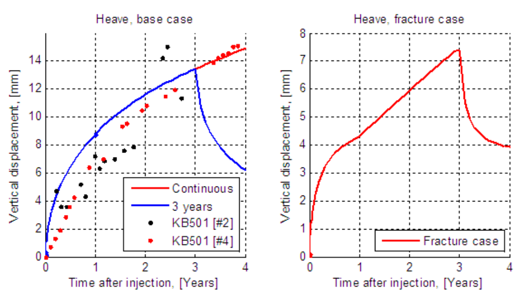

Figure 4. Left: Close-up (0-4 years after injection) of surface heave (modeled Base case; line) compared with measured data for injection well KB501 (dots). Red curve is from continuous injection and blue curve when injection is stopped after 3 years. Right: Close-up (0-4 years after injection) of surface heave (Fracture case).

Introducing a fairly thick (160 meter) and highly fractured layer above the reservoir in the caprock has a huge impact on the injection pressure, lowering it to almost 1/10 compared to Base case, which lowers the heave at the surface. In this study the size of the Base case model is chosen to give an injection pressure of app. 10-15 bar. It can be shown that by increasing the model domain size, the modeled injection pressure becomes lower, in the Fracture case the reservoir is in effect larger compared to Base case; hence the injection pressure is expected to be lower. So, whether there is a highly fractured layer, or not, above the reservoir at In Salah cannot be determined based on the injection over-pressure profile in this model alone (proper and correct boundary conditions are necessary in order to determine this and that requires much more details about the geology of the area).

However, by introducing a highly fractured layer between the injection reservoir and caprock the time evolution of the surface heave shows a distinct signature; an abrupt change in heave rate followed by an almost linear increase in heave with time, see figure 4, right. The change in rate occurs after one year, exactly when the plume reaches the intersection between the fracture zone and caprock. This profile is very different from the Base case, which has a smooth and declining heave rate profile, see figure 4, left. This indicates that a change in heave rate and time evolution profile above the injection site can say something about the thickness of the injection layer and the time the plume reaches the caprock. Also, preliminary studies indicate that anisotropy can strongly affect the heave rate change; increased anisotropy enhances the heave rate.

By comparing modeled data to reported heave data from In Salah, see figure 3, it can seem plausible, based on the flat heave profile, that for injection well KB501 and KB502 there is a fractured layer above the injection reservoir, in effect increasing the height of the injection reservoir. For injection well KB503, the round shape of the profile can indicate that the geology is somewhat layered like the model.

The Fault case model is very similar to the Base case, except that there is a high permeable vertical fault plane intersecting the caprock. The injection over-pressure profile is almost identical in shape and magnitude with the Base case, but not the heave footprint at the surface. When the fault goes all the way through the caprock a distinct and noticeable uplift of the surface is observed directly above it, see figure 5. The heave is not due to leakage as the plume barely reaches the fault plane in the reservoir, but to increased fluid pressure in the fault because of more favorable flow conditions (higher permeability). This indicates that a high permeable fault plane, even outside the reach of the injected CO_2 plume, can be visually detected at the surface.

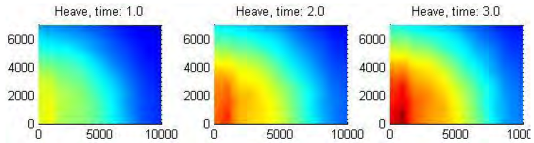

Figure 5. Vertical heave of the top surface (one half only is shown) at various times when the fault intersects the caprock. Color scale is vertical heave from 0-16mm.

A montage of the surface heave for the base case and the fault case is shown in figure 6; left: base case, center: fault case after 3 years, right: the difference.

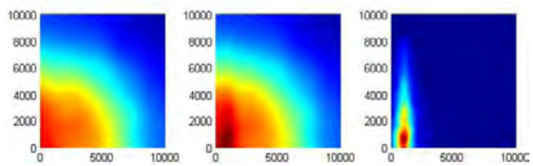

Figure 6. Left: Surface heave at surface, base case. Center: Surface heave fault case after three years. Right: difference between fault case vs. base case.

At In Salah, the opposite is observed; a reduction in heave above the suspected fault. This indicates that instead of having a fault with more favorable flow conditions, there is a sealing fault with lowered transmissibility across the fault plane. This case is not considered in this modeling exercise.

4. Conclusion

Excess CO_2 in produced oil and gas at In Salah is re-injected into the ground through three different walls: KB501, KB502 and KB503. Little details of the conditions are known hence a detailed analysis has not been performed, but rather a simplified geological model with some key hydraulic and elastic features. Some case studies have been performed to investigate various impacts on the surface heave: Base case; best-guess estimate of the available parameters, Fracture case; inserting a high permeable lower caprock layer (in effect increasing the thickness of the reservoir) and Fault case; adding a high permeable vertical fault plane through the caprock.

The results from the Base case show that there is expected a significant degree of heave of app. 13 mm after only 3 years of injection above the injection site and this will steadily increase with continuous injection.

Base case model shows a smooth and steadily declining heave rate curve, while the Fracture case gives a distinct shape of the surface heave profile; an abrupt change in heave rate followed by an almost linear increase in heave with time. The change in rate occurs when the plume reaches the caprock, or top of the fractured layer, indicating that the heave profile can say something about the thickness of the injection layer and the time that the plume reaches the caprock. The requirement for the thickness of the layer to give this distinct signature is not investigated.

By comparing modeled data to reported heave data from In Salah it can seem plausible, based on the flat heave profile, that for injection well KB501 and KB502 there is a fractured layer above the injection reservoir. For injection well KB503, the round shape of the profile can indicate that the geology is somewhat layered like the Base case model.

By introducing a vertical fault plane through the caprock, a distinct and noticeable uplift of the surface directly above it is observed. The heave is not due to leakage, but to increased fluid pressure in the fault because of more favorable flow conditions (higher permeability). This indicates that a high permeable fault plane, even outside the reach of the injected CO_2 plume, can be visually determined by measurements like InSAR.

5. References

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